United States
Environmental Protection
Agency

Region 8
Suite 103
1860 Lincoln St.
Denver, CO. 80295

Colorado, Montana,
North Dakota,
South Dakota,
Utah, Wyoming

EPA

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6-19-80

Mr. Joseph C. Fackrell
Project Manager
Intermountain Power Project
Post Office Box BB
Sandy, Utah 84070

Dear Mr. Fackrell:

We have completed final review of your application to construct and operate a 3,000 megawatt power plant near Lynndyl, Utah, and hereby issue conditional approval pursuant to U.S. Environmental Protection Agency (EPA) Prevention of Significant Deterioration (PSD) of Air Quality regulations, 40 CFR, Section 52.21 (as amended 43 FR 26388).

The conditional permit shall become effective in accordance with Article IV of the enclosed permit. Construction and operation may not take place if this permit or any part thereof is rejected.

If you have any questions, please contact Mr. John T. Dale of my staff at (303) 837-3763.

Sincerely yours,

Robert L. Duprey, Director
Air and Hazardous Materials Division

Enclosures

cc: Mr. John Avalos
Mr. Brent C. Bradford, Bureau of Air Quality

CONDITIONAL PERMIT TO COMMENCE CONSTRUCTION AND OPERATE

40 CFR 52.21(i), as amended June 19, 1978 (43 FR 26388)
Significant Deterioration of Air Quality
Review of New Sources

Intermountain Power Project
Four 750 MW Units
Lynndyl Site

I. INTRODUCTION

Intermountain Power Project (hereinafter "the Company") plans to construct four 750 (net) megawatt coal fired electric generating units (hereinafter "the Source") 11 miles west of Lynndyl, Utah.

On July 7, 1977, the Company requested from the U. S. Environmental Protection Agency, Region VIII (hereinafter "EPA"), permission to construct the Source at a location near Hanksville, Utah, which was called the Salt Wash site. The Company was notified on December 8, 1977, that all atmospheric diffusion modeling indicated that the Class I sulfur dioxide air quality increments would be exceeded in the Capitol Reef National Park area. Some of the modeling studies also indicated violations of the Class II increments on elevated terrain. The Company requested that EPA hold the review in abeyance on January 9, 1978.

The Company requested EPA to consider the Lynndyl site for the power plant on August 7, 1978. Additional information was submitted regarding the Lynndyl site on October 2, 1978. A contractor, PEDCo Environmental, Inc., was selected by EPA to help with the best available control technology (BACT) review and requested some clarifying information about the plant on April 30, 1979. The Company provided this information on August 17, 1979. A public hearing was held in Salt Lake City on January 10, 1980. Public comments were requested during the periods of December 13 through January 17 and March 27 through April 17, 1980.

A partial listing of information considered by EPA in its review is contained in appendix I. A summary of written comments appears in appendix II.

II. FINDINGS

On the basis of information in the administrative record (see appendix I for partial listing), EPA has determined that:

(1) The Company, through application of BACT as defined in 40 CFR, Section 52.21(b)(10), will limit emissions from the four units as set forth in III below;

(2) The Intermountain Power Project emissions will not cause exceedences of applicable air quality increments;

(3) Violations of the national ambient air quality standards will not be caused or exacerbated by the facility;

(4) EPA has good reason to believe that the Company can comply with the conditions of this permit. However, in the issuance of this permit, EPA does not assume any risk of loss which may occur as a result of the commencement of construction and operation by the Company, if conditions of this permit are not met by the Company.

III. CONDITIONAL PERMIT TO CONSTRUCT AND OPERATE

On the basis of the findings set forth in II above, and pursuant to the authority (as delegated by the Administrator) of 40 CFR 52.21(r)(2), EPA hereby grants conditional approval for the Intermountain Power Project to commence construction and operation of four 750 MW coal fired electric generating units. This approval is expressly conditioned as follows:

(1) Each unit shall not cause to be discharged into the atmosphere sulfur dioxide at a rate exceeding:

(a) 0.150 pounds per million Btu heat input as averaged over 30 successive boiler operating days, and

(b) 10 percent of the potential combustion concentration (90 percent reduction) as averaged over 30 successive boiler operating days.

(c) Compliance with the emission limitations of this condition shall be based solely on data from the Continuous Emission Monitors (CEM) as provided for in condition 4 and appendix III of this permit. Compliance with the percent reduction requirements of (1)(b) may be based on a combination of CEM and fuel analysis data as provided for in 40 CFR 60, appendix A, method 1a. in place of CEM's at the inlet and outlet of the sulfur control device.

(2) Each unit shall not cause to be discharged into the atmosphere particulate matter at a rate exceeding:

(a) 0.020 pounds per million Btu heat input, as averaged over 8 hours (minimum) of reference method testing, and

(b) Opacity of 20 percent, as averaged over each separate 6-minute period, except for one 6-minute period per hour of not more than 27 percent opacity.

(c) Compliance with part (a) of this condition shall be as provided for in 40 CFR 60, appendix A, method 5. Four (4) 2-hour runs shall be conducted as provided for in 60.8 of appendix III. Compliance with part (b) shall be as provided for in 40 CFR 60, appendix A, method 9 and data from CEM under condition (4) and appendix III of this permit.

(3) Each unit shall not cause to be discharged into the atmosphere nitrogen oxides, expressed as NO_2, at a rate exceeding 0.550 pounds per million Btu heat input based on a 30-day rolling average. Compliance with this emission limit shall be based solely on CEM data as provided for in condition (4) and appendix III of this permit.

(4) A continuous monitoring system for measuring opacity, optical density, sulfur dioxide, nitrogen oxides, and diluent shall be installed, calibrated, maintained, and operated by the owner or operator. Procedures to be followed for (1) testing, monitoring, and reporting of excess emissions of particulates, opacity, sulfur dioxide, and nitrogen oxides, and for (2) the purposes of demonstrating compliance with the emission limitations of conditions (1), (2), and (3) are specified in the applicable sections of 40 CFR 60.7, 60.8, 60.11, 60.13, subpart Da, and Reference Methods Performance Specification Nos. 1, 2, and 3, of 40 CFR Part 60, appendices A and B, as is amended by appendix III of this permit, and which is incorporated as a part of this condition by reference. Production-weighted values referred to in appendix III are not applicable to this permit.

A quality control program for the continuous monitoring system must be developed and implemented. As a minimum, the quality control program must have written procedures for each of the following activities:

(a) Installation of CEM's

(b) Calibration of CEM's

(c) Zero and calibration checks and adjustments for CEM's

(d) Preventive maintenance for CEM's (including parts inventory)

(e) Data recording and reporting

(f) Program of corrective action for inoperable CEM's

(g) Annual evaluation of CEM system

The quality control program must be described in detail, suitably documented, and approved by EPA Region VIII's Quality Assurance Office.

(5) (a) The Company shall submit to EPA all plans which relate to the design, engineering, and operation for the Source's particulate, NO_x and SO_2 control systems. The information shall include, at a minimum, a description of the system's operation, major design parameters, and efficiency or emission rate quarantees. Such information should, in addition, be accompanied by at least one complete unpriced copy of the contract the Company plans to accept for the purchase or construction of the systems. This information will be submitted within 30 days after receipt of the executed contract by the Company.

Should EPA, in its discretion, determine that the Company's final plans contain insufficient information to permit an independent evaluation of this system, it shall so notify the Company within 30 days after receiving the plans. The Company shall have 30 days thereafter to submit further design, engineering, and operating data. If, after reviewing these further data, EPA determines that there still is insufficient information or determines that the system will not enable the Company to meet and demonstrate compliance with the emission limits and conditions set forth in this permit, the EPA and the Company may meet within 60 days of this determination to discuss alternative control options. Pursuant to these discussions, EPA and the Company may determine a schedule for development and submittal of information on additional and/or modified control systems which will enable compliance with the emissions limits and conditions set forth in this permit. EPA shall review this additional information to determine whether the revised system will enable the Company to meet and demonstrate compliance with the emission limits and conditions set forth in this permit. If, after reviewing this further information, EPA determines that the additional and/or modified control system will not enable compliance with the emission limits and conditions set forth in this permit, then this permit to construct and operate may, upon notification of the Company, be denied ab initio. Failure by EPA to take such action shall not, however, constitute an endorsement of the methods chosen by the Company to reduce air emissions; nor shall such failure guarantee that these methods will, in fact, enable the Company to meet the condition of this permit. Any determination that the information submitted is insufficient or that the proposed control system will not enable compliance shall be accompanied by a written statement of reasons, identifying the criteria applied and the factors considered. Onsite construction of any major equipment shall not commence before the control equipment design has been evaluated and approved by EPA.

(b) No coal shall be burned which is incompatible with the Company's control equipment design. Coal quality data shall be submitted within 30 days after it becomes available and shall include variations in quality as well as average data. This coal quality data shall include the following:

(i) Mine locations

(ii) Quantity of coal expected from each location

(iii) How the coal will be mined, handled, and shipped

(iv) Data base used to calculate average and worst case coal quality

(v) Worst case coal quality that could be delivered over a 30-day period

(vi) How any blending of the coal will naturally or intentionally occur (if applicable)

(vii) Contract guarantees for each coal supply

(viii) How non-specification coal will be stored, handled, and blended (if applicable)

(ix) Coal quality values shall include Btu value, sulfur content, ash content, and moisture content

(6) Dust control on unpaved roads shall be accomplished by the application of chemical stabilizing agents supplemented with water. The water and chemicals shall be added at a rate and frequency to minimize visible emissions when vehicles are using the roads. Records will be kept on the type, amount, and frequency that the chemicals are applied.

(7) The emission control equipment presented in the application for handling the coal, lime, and ash shall be utilized. Records will be kept of the type of wet suppression used and the rate of application.

(8) This authority to construct and operate the Source does not relieve the Applicant of the obligation to comply with all other applicable federal, state or local regulations.

(9) The Company shall prepare an air quality monitoring plan that will determine the impact of Source emissions on air quality. The Utah State Division of Health (Bureau of Air Quality) shall approve the site locations, instrumentation, duration of data collection, and determine if the plan should be implemented. All air quality monitoring must conform to the requirements of 40 CFR part 58. As part of the air quality monitoring program, a quality control program must be developed and implemented and consist of policies, procedures, specifications, standards and documentation necessary to:

(a) Meet the monitoring objectives and quality assurance requirements of the permit granting authority.

(b) Minimize loss of air quality data due to malfunctions or out-of-control conditions.

(10) Compliance provisions for conditions (1), (2), and (3) shall be in accordance with the appropriate sections in 40 CFR 60.46a.

(11) The owner or operator shall abide by all presentations, statements of intent, and agreements contained in IPP's application and in all additions, modifications, and corrections thereto, as presented for public inspection.

IV. GENERAL

This permit is issued in reliance upon the accuracy and completeness of the information set forth in the Company's application to EPA for permission to commence construction. The conditions herein become, upon the effective date of this permit, enforceable by EPA pursuant to any remedies it now has, or may in the future have, under the Clean Air Act. Each and every condition is immediately effective unless within ten (10) days after receipt you notify this Regional Office in writing (Attention: Norman A. Huey, 8AH-A) that the permit or a term or condition thereof is rejected. Such notice should include the reason or reasons for rejection.

The United States Court of Appeals for the D.C. Circuit has issued a ruling in the case of Alabama Power Co. vs. Douglas M. Costle (78-1006 and consolidated cases) which has significant impact on the EPA prevention of significant deterioration (PSD) program. The applicant is hereby advised that this permit may be subject to reevaluation as a result of the final Court decision and its ultimate effect.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII

BY:
Robert L. Duprey, Director
Air and Hazardous Materials Division

DATE: June 5, 1980

APPENDIX I

NO.	DESCRIPTION	Date
1.	Westinghouse Electric Corp. (A. Roffman) to EPA D. Henderson)	04-19-76
2.	Westinghouse Meeting Handout	05-03-76
3.	Intermountain Power Project (IPP) Modeling Meeting Report (D. Henderson)	05-06-76
4.	Department of Interior - Canyonlands and Capitol Reef National Park to Become Class I Areas (C. Andrus)	06-14-77
5.	Department of Interior - Notice of Possible Redesignation (J. Henneberger)	06-14-77
6.	IPP (J. Fackrell) Application for a PSD Permit at the Salt Wash Site (a) Volumes I through V of the IPP Preliminary Engineering and Feasibility Study Report	07-01-77
7.	EPA (J. Green) to IPP (J. Anthony)	07-07-77
8.	EPA (F. Longenberger) Memo About Request for Additional Information	07-29-77
9.	EPA (F. Longenberger) Memo	08-01-77
10.	EPA (D. Henderson) to BLM (J. Littlejohn)	08-08-77
11.	IPP (J. Anthony) Supplemental Permit Application Information to EPA (J. Green)	08-10-77
12.	Air Modeling Task Force Meeting Minutes	08-30-77
13.	EPA (D. Henderson) Meeting Report	09-15-77
14.	EPA (N. Huey) to IPP (J. Anthony)	09-21-77
15.	EPA (N. Huey) to IPP (J. Anthony)	10-12-77
16.	EPA (F. Longenberger) Engineering Review	10-21-77
17.	EPA (D. Henderson) Air Quality Estimates	11-14-77

18.	EPA (N. Huey) Permit Status Report	12-13-77
19.	IPP (J. Fackrell) Request to Hold Permit Application in Abeyance to EPA (D. Wagoner)	01-05-78
20.	IPP (J. Anthony) to H. E. Cramer Co. (J. Bowers)	07-06-78
21.	IPP (J. Fackrell) Application for a PSD Permit at the Lynndyl Site to EPA (A. Merson) (a) Calculated Air Quality Impact of the Emissions from the Proposed IPP Power Plant at the Lynndyl Site	07-25-78
22.	IPP (J. Fackrell) to Utah Bureau of Air Quality (A. Rickers)	07-25-78
23.	IPP (J. Anthony) Supplemental Information submitted to EPA (F. Longenberger)	09-26-78
24.	EPA (N. Huey) to Los Angeles Department of Water and Power (J. Avalos)	10-26-78
25.	IPP (J. Anthony) to PEDCo Environmental Services (J. Zoller) (a) Volume I through V of the IPP Preliminary Engineering and Feasibility Study (b) Calculated Air Quality Impact of the Emissions from the Proposed IPP Power Plant at the Lynndyl Site	01-29-79
26.	IPP (J. Anthony) Notification that Proposed Lynndyl Site would be moved 1800 feet to EPA (J. Rakers)	04-13-79
27.	PEDCo Environmental, Inc. (J. Zoller) Request Supplemental Information to Los Angeles Department of Water and Power (J. Avalos)	04-30-79
28.	IPP Preliminary Engineering and Feasibility Study Volume VI - Lynndyl Alternative Site	04-79
29.	H. E. Cramer Company (J. Bowers) Final Report on the Visibility Impacts of the Proposed IPP Power Plant at the Lynndyl Site to EPA (N. Huey)	06-18-79
30.	BLM Draft Environmental Statement for the Intermountain Power Project	
31.	IPP (J. Anthony) Response to PEDCo Questions to EPA (J. Rakers)	08-09-79
32.	PEDCo Environmental, Inc. (J. Zoller) BACT Determination to EPA (N. Huey)	10-25-79

33.	EPA (J. Dale) to Los Angeles Department of Water and Power (J. Avalos)	10-31-79
34.	EPA (R. Duprey) proposed permit and analysis to IPP (J. Fackrell)	12-07-79
35.	Public Notice in the <u>Millard County Chronicle</u>	12-13-70
36.	Public Notice in the <u>Salt Lake City Tribune</u>	12-14-79
37.	Transcript of Public Hearing held on January 10, 1980	1-10-80
38.	IPP (J. Anthony) comments about proposed permit to EPA (N. Huey)	1-10-80
39.	IPP (J. Anthony) request for delay in issuring the PSD permit to EPA (R. Duprey)	1-24-80
40.	IPP (J. Anthony) request to reopen pulic comment period so they might submit additional comments to EPA (N. Huey)	3-21-80
41.	Public Notice in the <u>Millard County Chronicle</u>	3-27-80
42.	IPP (J. Anthony) comments on proposed PSD permit conditions to EPA (N. Huey)	4-1-80
43.	EPA (R. Duprey) request for technical assistance regarding BACT for NO_x to EPA (W. Barber and J. Burchard)	4-01-80
44	Transcript of meeting between EPA and IPP	4-08-80
45.	State of Utah (A. Rickers) to EPA (N. Huey)	4-14-80
46.	IPP (J. Anthony) coal quality letter to EPA (N. Huey)	4-17-80
47.	EPA (N. Huey) to IPP (J. Anthony)	4-28-80
48.	Hunton and Williams (H. Nickel) comments on proposed IPP permit to EPA (N. Huey)	4-17-80
49.	KVB (D. Baker) comments on proposed IPP permit to EPA (N. Huey)	4-17-80
50.	EPA (J. Burchard and W. Barber) technical assistance regarding IPP to EPA (R. Duprey)	4-21-80
51.	Stearns-Roger (D. Packnett) to EPA (N. Huey)	4-24-80

52.	EPA (J. Dale) technical memo	5-21-80
53.	EPA (D. Lachapelle) clarification of 0.55 NO_x emission	5-22-80
54.	EPA (W. McClave) telephone memo	5-22-80
55.	EPA (R. Fisher) technical memo	5-30-80

INTERMOUNTAIN POWER PROJECT
APPLICATION ANALYSIS

January 25, 1980

A. Applicability Determination

The proposed Intermountain Power Project (IPP) will consist of four coal fired electrical power units that will generate 750 megawatts each for a total of 3,000 megawatts. Emissions from the Source will be from the two main stacks, coal handling, lime handling, ash handling, and haul roads.

Estimated emissions from the proposed operations are as follows:

PARTICULATES

Operation	Potential (tons/yr)	Actual (tons/yr)	Allowable (tons/yr)
Two-stacks	939,552	2,120	3,348
Coal Unloading	200	3	N/A
Coal Crushing	758	1.5	N/A
Coal Conveying	250	25	N/A
Conveyor Transfer	500	6	N/A
Coal Storage	1,208	120.8	N/A
Lime Transfer and Storage	17	0.1	N/A
Ash Silo Unloading	9,390	94	N/A
Haul Roads	341	5	N/A
Total Particulates	952,208	2,375.4	

Other pollutants are only emitted from the main stacks and are estimated as follows:

Pollutant	Potential (tons/yr)	Actual (tons/yr)	Allowable (tons/yr)
SO_2	164,032	16,404	49,210
NO_x	98,195	61,371	61,371
CO	5,468	5,468	N/A
HC	1,641	1,641	N/A

The proposed IPP plant is subject to review as required under Section 52.21 (i) for emissions of particulates, sulfur dioxide, nitrogen oxides, carbon dioxide and hydrocarbons.

B. Application Overview

A revised PSD permit application was received on August 7, 1978, for the proposed Lynndyl site. Additional information was requested and received during the following year. The last date that information was provided was August 17, 1979. The proposed plant is being reviewed in accordance with the Prevention of Significant Deterioration Regulations as promulgated on June 19, 1978.

C. Control Technology Review

A control technology review must consider particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, and hydrocarbons. The proposed plant has been reviewed and it has been determined that applicable State Implementation Plan emission limitations, and emission standards under 40 CFR Part 60 and Part 61 will be met (see Attachment No. 1).

Process emissions of carbon monoxide and hydrocarbons are assumed to meet the best available control technology (BACT) requirements because no control technology is available.

The Weir horizontal scrubber is expected to achieve a 90 percent removal of sulfur dioxide emissions and result in 0.15 lbs/MM Btu at the expected worst fuel sulfur content. Current New Source Performance Standards (NSPS) would require 70 percent removal of SO_2 emissions.

Particulate emissions are expected not to exceed 0.02 lbs/MM Btu with the use of the hot side ESP followed by the horizontal scrubber. NSPS limit particulate emissions to 0.03 lb/MM Btu.

Nitrogen oxides emissions are expected to meet and emission limit of 0.55 lbs/MM Btu. Although much of the coal burned may be classified as bituminous, which would be allowed an emission limit of 0.6 lbs/MM Btu under NSPS, the sulfur content will remain low (less than one percent). Therefore, tube wastage should not pose the same problem as with high sulfur (Eastern) bituminous coals when the boiler operations creates a reducing atmosphere which often accompanies low NO_x operation. Tests have indicated that an existing plant, burning coal similar to that which IPP will burn, achieves a NO_x emission limit of 0.54 lbs/MM Btu on a 30-day average without excessive slagging problems. The allowable emission limit required to meet BACT requirements should therefore be 0.55 lbs/MM Btu when the low sulfur bituminous coal is being burned.

Particulate emissions from the coal handling operations will be controlled by using enclosures, water sprays with a surfactant, surface crusting agents, and fabric filters. Transfer and handling of lime will have emissions vented into a fabric filter. A hydro-mixer will be needed to add water to dry ash which will help control fly ash emissions. The landfilled fly ash and SO_2 sludge will be stabilized to minimize emissions during unloading operations. Any unpaved roads should have emissions controlled by the addition of chemical dust suppressants and supplemented with water.

It is EPA's opinion that the IPP's proposal for the plant along with conditions imposed by the PSD permit represents BACT as required by the PSD regulations (see Attachment #1).

D. Stack Heights

The degree of emission limitation required for control of any air pollutant under the PSD regulations shall not be affected in any manner by a stack height which exceeds good engineering practice. The height of the two main stacks at the IPP plant were planned to be 750 feet when the plant was to be at the Salt Wash site. The planned stack height was changed to 710 feet when the plant location was changed to the Lynndyl site. Good engineering practice (GEP) for the stack heights is defined by a height not over the height of a nearby structure plus one and a half times the lesser dimension (height or width) of the nearby structure. The height of the boilers is less than the width of the boilers. GEP for the IPP plant is as follows:

GEP had n[illegible] [illegible] bar - previous) Salt Wash

GEP = 2.5 (height of boilers)

GEP = 2.5 (284 feet) = 710 feet

The air quality impact was determined using the GEP stack heights.

E. Air Quality Models

Title 40, Part 52, Section 52.21(m) requires that ambient impact analyses shall be based on diffusion models specified in the "Guidelines on Air Quality Models" (OAQPS 1.2-080). The applicant did not use a "Guideline" model but EPA Region VIII did use CRSTER, a "Guideline" model, to substantiate the applicant's results for both 24 and 3-hour impacts.

The annual impact is predicted by the applicant's model to be very small. EPA concurs with these results but has not used a "Guideline" model to substantiate this.

F. Air Quality Review

Maintenance of NAAQS

Available ambient monitoring data taken near the proposed site have shown occasional violations of the 24-hour TSP standard while measured concentrations are well within the national annual standard (45 ug/m^3 at the highest site). The occasional short-term violations are caused by rural fugitive dust uncontaminated by industrial pollution and do not occur under conditions when the proposed facility is expected to have its highest contribution (6 ug/m^3). Thus, the proposed facility would not contribute to violations of the national standards.

Maintenance of the Increments

At the points of maximum impacts of the stack emissions in Class I and Class II areas, the analysis shows that there would be no violations of the applicable increments. A summary of the air quality analysis is contained in attachment 2. For fugitive emission impacts on Class II areas, see Response 1f of appendix II.

G. Monitoring

Pre-construction monitoring under 52.21(n) should not be required because the PSD application was not submitted after August 7, 1978.

A post-construction ambient air quality monitoring plan will be prepared for SO_2 and particulate matter to determine the impact that plant emissions are having on the air quality. The duration of data collection, site locations, and instrumentation requirements will be approved by the Utah State Division of Health (Bureau of Air Quality).

H. Additional Impact Analysis

Visibility

Information concerning the visibility impact around the Lynndyl Site is contained in a report dated June 1979 and entitled "Calculated Visibility Impacts of Emissions from the Proposed IPP Power Plant at the Lynndyl Site."

EPA has reviewed this information and is of the opinion that the results of the visibility impact calculations do not indicate a need to change the design of the IPP plant or deny the permit.

Soils and Vegetation

IPP discussed additional impacts that would result on soils, vegetation and air quality because of the plant and associated growth in a letter dated September 26, 1978. It was concluded from the study that the impact would be nondetectable.

General Growth

The analysis included the impact from the normal work-day operating force of 475 people. Access roads to and from the plant are paved so that traffic associated fugitive dust emissions will be negligible. Both construction and operating impacts associated with the growth requirements due to workers and their families were considered in Section 8.5 F of the draft environmental statements.

I. Public Participation

The application, analysis, and proposed permit were made available for public inspection at the EPA offices in Denver and the Utah Bureau of Air Quality offices in Salt Lake City. The EPA analysis and proposed permit were made available at the Millard County Clerk's office in Fillmore, Utah. A public hearing was held on January 10, 1980, in Salt Lake City. A public notice regarding our proposed action was issued in the Salt Lake City Tribune on December 14, 1980, and the Millard County Chronicle on December 13, 1979. No comments were made during the public hearing. Three written comments were received before the public comment period closed on January 17, 1980. These comments were considered in the final permit and are summarized in the summary of public comments (Appendix II of the permit).

On January 24, 1980, IPP requested that EPA delay issuance of the PSD permit until it could evaluate certain conditions in the proposed permit. IPP requested a reopening of the public comment period so it could submit additional material regarding the permit. A public notice was issued in the Millard County Chronicle on March 27, 1980, which reopened the comment period until April 17, 1980, and gave notice of a meeting with IPP on April 10, 1980, to discuss certain conditions in the permit. One-hundred and ninety three public comments were received and considered in the final permit. These comments are also summarized in appendix II of the permit.

APPENDIX II

IPP Power Plant
Summary of Public Comments

Comment 1a: The potential emission estimate for NO_x emissions of 98,195 tons per year appears to be very high.

Response 1a: Potential NO_x emissions were estimated to be those that would occur if the burners were not designed for NO_x control. The EPA Compilation of Air Pollutant Emission Factors (AP-42) was used to estimate uncontrolled (potential) NO_x emission.

Comment 2a: The application analysis stated that the height of the two main stacks will be 750 feet. The height of the stacks was changed to 710 feet when the project was relocated from Salt Wash to Lynndyl.

Response 2a: A correction has been made.

Comment 3a: The calculated SO_2 emission rate was 0.155 pounds per million Btu's heat input. Shouldn't the allowable emission limit be rounded off to 0.16 instead of 0.15.

Response 3a: Because of the tentative nature of the provided coal quality data, the sensitivity of the estimated emission rate does not warrant such exactness.

Comment 4a: The 90 percent reduction in SO_2 emission is redundant since the emission rate is based on that amount of control.

Response 4a: The sulfur and Btu value of coal will vary considerably. Operation of the control equipment in the most efficient manner will result in variations in the emission rate but can be demonstrated by a constant emission reduction.

Comment 5a: The optical density is a feature of the opacity measuring device that does not lend itself for continuous monitoring and the requirement should be deleted.

Response 5a: All equipment manufacturers do have the capability of producing an optical density output. It should be reported as a value averaged over about 1 hour.

Comment 6a: Permit conditions should contain a general discussion as to when the emission limits proposed are enforceable and when exemptions apply.

<u>Response 6a</u>: Changes have been made to the permit. Condition number (10) was added to indicate exemptions.

<u>Comment 7a</u>: EPA's decision to revise the proposed NO_x emission limit when burning bituminous coal from 0.6 to 0.5 pounds per million Btu's heat input is more stringent than new source performance standards (NSPS). Since IPP has recently committed itself to burning Utah bituminous coal, the NSPS emission limit of 0.6 pounds per million Btu's heat input should remain as the permit condition.

<u>Response 7a</u>: It is EPA's responsibility to conduct a control technology review under the PSD regulations which will determine what is best available control technology (BACT) for each applicable pollutant. BACT must be an emission limit based on the maximum degree of emission reduction which the Administrator, on a case-by-case basis, determines is achievable for the source. In no case can a determination of BACT result in emissions which would exceed any applicable NSPS. Review of the preamble to the NSPS in the <u>Federal Register</u> dated June 11, 1979, made it clear that EPA had data available that would support an emission limit of 0.5 pounds per million Btu's heat input for coal burning boilers (pages 33586 and 33587). The Administrator established a higher emission limit of 0.6 pounds per million Btu's for when bituminous coals are burned to reduce the potential for increased tube wastage during low NO_x operation. The severity of the tube wastage is believed to vary with several factors, but especially with the sulfur content of the coal burned. Bituminous coals with a low sulfur content should not experience this problem and, therefore, the higher emission rate should not be needed to prevent excessive boiler tube wastage. BACT for boilers burning coal that would not experience excessive tube wastage at low NO_x conditions should be an emission limit of 0.5 pounds per million Btu's heat input.

Information was later provided which showed that a Utah "B" bituminous similar to what IPP will burn causes slagging problems. This operational problem was solved by increasing the excess air which increases NO_x emissions. Memos from the EPA Industrial Enviromental Research Laboratory and the EPA Office of Air Quality Planning and Standards confirm that the Utah "B" bituminous can be burned in a manner to reduce slagging and achieve a NO_x emission limit of 0.550 $lbs/10^6$ Btu based on a 30-day rolling average. The final BACT decision for the NO_x limit in the permit (0.55) reflects consideration of all the above information and comments.

<u>Comment 1b</u>: Coal fired plants now built can clearly deposit acid precipitation on dry deposition greater than sulfuric acid. If the

synfuels program actually becomes operative in the coal bearing section of Utah, our agricultural lands could become permanently acidic. We are concerned not only about specific plants such as IPP but combined totals and their effects.

Response 1b: One way to minimize the potential for acid precipitation is to control sulfur dioxide and nitrogen oxide emissions to the maximum extent possible. This is one of the purposes of the PSD regulations. Sources must install and operate equipment that will meet best available control emission limits. As each new plant is proposed, it must be evaluated along with existing plants to insure that no violations of air quality standards will occur. EPA has determined that IPP will meet these requirements and, while acid precipitation is a growing problem, a permit will be issued because the required regulation is met.

Comment 2b: University of Montana botanist Clancy Gordon has demonstrated damage to vegetation by pollution from coal fired plants in Montana. I am concerned with the problem of projected statewide emissions and their effects on agriculture.

Response 2b: Some sites relatively close to the Colstrip power plant appear to show changes in incidences of foliar pathologies, sulfur concentrations, and fluoride concentrations. However, there is no conclusive available evidence to support the contention that the emissions of Colstrip 1 and 2 are causing this. Experiments conducted in 1978 to assess the long term consequences of relatively low level chronic SO_2 exposure to native grassland showed that the concentrations necessary to have a demonstrated effect were 1-2 orders of magnitude greater than those observed near the Colstrip units.

The maximum allowable SO_2 concentrations permitted by the PSD regulations will prevent IPP's emissions from reaching the level at which these effects have been demonstrated.

Comment 1c: In order to continue your fight to clean our air and protect our health, I hope you will prevent the construction of any new plants including IPP that will soil our air, ruin our environment, and endanger our health both physical and emotional. I hope you will continue to demand that regulations be met and that we continue to improve.

Response 1c: The PSD regulations require that best available control technology be utilized to control emissions and that certain air quality standards not be violated. EPA believes that IPP will fulfill these requirements when they comply with the conditions contained in the PSD permit.

Comment 1d: Proposed permit condition (1)(c) requires compliance be determined solely through use of continuous monitors. By implication then, this condition would not allow IPP to show compliance through a combination of fuel tests and continuous monitors. Without such a combination, IPP will be unable to receive credit for sulfur removed prior to or during combustion.

Response 1d: Changes to condition (1)(c) and the appendix III have been made to allow credit for sulfur removal before the SO_2 flue gas desulfurization systems. This sulfur removal can be counted in the 90 percent reduction requirement in condition (1)(b).

Comment 2d: An emission limit in the PSD permit of 0.5 pounds per million Btu's heat input for NO_x emissions should not be required when the IPP plant is burning bituminous coal but the 0.6 pounds per million Btu's limit required by new source performance standards (NSPS). Compliance with a NO_x emission limit more stringent than the recently adopted NSPS limits could introduce corrosion, tube wastage, and slagging problems. These problems would affect boiler reliability, customer service, and electrical rates.

Response 2d: The higher emission limit of 0.6 pounds per million Btu's was allowed under NSPS because of concern over the potential for accelerated boiler tube wastage (i.e. corrosion) during low NO_x operation of boilers when burning coal that would create that problem. Evidence that the coal which IPP will burn would cause this problem was used in the BACT evaluation. However, evidence is that the coal should not cause accelerated boiler tube wastage. The severity of tube wastage is believed to increase directly with the sulfur content of the coal burned, and IPP has projected that the sulfur content of their coal will range between 0.44 and 0.78 percent. This is low in comparison to the typical bituminous coal for which concern about accelerated tube wastage was expressed in the NSPS promulgation. The problem about excessive slagging problems when burning the IPP coal had not been expressed earlier. It was, however, evaluated in the BACT determination.

Comment 3d: The automatic revocations condition is inconsistent with the intent underlying the revisions to EPA's PSD regulations proposed in September 1979. The proposed permit provides that it will be automatically revoked if EPA determines that IPP's "final plans" do not contain sufficient information "to permit an independent evaluation of this system," or if EPA determines that the system will not achieve the emission limits set forth in the PSD permit. See Response 7a.

It should be emphasized that voiding a permit has extremely serious consequences. Not only would it require reapplication for a permit, but it would jeopardize the sources entitlement to the increments allocated to it as a result of the original permit.

Region VIII, therefore, should not void the permit based on a finding concerning the proposed application of pollution control equipment. Rather, as EPA has recognized in the past, the appropriate remedy is to disapprove application of the proposed control technology if it is found that the proposed system would not achieve the applicable emission limits. The source then would be required to obtain approval of a new control system before the facility could commence operation.

Response 3d: The PSD regulations seem to contemplate that no permit should be issued at all until EPA obtains the information necessary to determine that BACT will be applied. We have issued permits to electric power plants without having the necessary information to know if BACT will be applied because of the long lead times needed for construction. We have included conditions in the permit requiring that the necessary information be required and evaluated prior to on-site construction of the plant. Region VIII does not see the automatic revocation condition as being inconsistent with the PSD regulations. If the control equipment information submitted with the PSD application had been found inadequate or it had been determined that it would not achieve the BACT requirements, a PSD permit would not have been issued. We do not agree that the plant should be allowed to commence construction without having an emission control equipment design capable of meeting the emission limits in the permit. The permit has been changed to accommodate due process concerns of IPP.

Comment 4d: Condition (5) in the proposed permit requires IPP to "select" the coal supply and to "finalize control equipment design" before on-site construction of major equipment commences. This sentence should be stricken because final selection of all of the coal supplies for the first several years of plant operation may not be completed before 1983-84. On-site construction is scheduled to begin in 1981. IPP will identify the range of coal quality to be used in conjunction with its selection of pollution control equipment. Information on coal supplies will be reported as it becomes available. However, to require that IPP purchase coal before commencing on-site construction of major equipment is impractical. Similarly, the requirement that control equipment design be finalized before on-site contruction of major equipment begins should be deleted.

Response 4d: This condition has been modified to require only approval of the control equipment design prior to on-site construction of major equipment. Also, included is a requirement that coal shall not be burned which is incompatible with the control equipment design.

Comment 5d: Condition (5) does not indicate what standards are to be applied by the person reviewing the proposed equipment, how that person is to judge adequacy of the equipment, who must meet the burden of showing inadequacy, or how long the Region may take in reviewing the proposed equipment.

Response 5d: The standards to be used in reviewing the proposed equipment is the same as required under the PSD requirements to determine that best available control technology will be applied. EPA will attempt to evaluate the system within 30 days. However, EPA may decide to have an outside independent evaluation done under a contract which would take longer. To insure that delays will not occur in the project, detailed information should be submitted as soon as possible.

Comment 6d: The continuous monitoring requirements in the permit can be required under EPA's statutory authority in Section 114 of the Clean Air Act. The monitoring requirements must meet the test of reasonableness.

The monitor availability requirements proposed by Region VIII in appendix III are far more stringent than those set forth in the new NSPS regulations. The requirements should, therefore, be modified to conform to the NSPS regulations, which reflect the Administrator's conclusions as to the type and amount of emission monitoring that may reasonably be required of new source owners.

The permit also requires that if continuous monitors do not meet the prescribed availability requirements for two successive quarters, IPP must replace the monitors with no assurance that the replacement system would meet the proposed availability requirements. Again, the approach of the revised NSPS should be followed.

Response 6d: Region VII EPA believes the permit monitoring requirements do meet the test of reasonableness. It is our position that the Region VIII permit monitoring requirements will not require different types or more emission monitoring equipment or more sophisticated technology over that required by th NSPS regulations. The state-of-art of emission monitoring does support the permit prescribed monitor availability requirements. Furthermore, the 85% (annual)/75% (quarter) availability requirement is not a firm fixed standard as is the 55% monthly availability requirement of the NSPS. Section 60.13(e)(4)(ii) of appendix III of the permit allows variances from the availability requirements by allowing time periods of poor instrument availability to not be counted for the purpose of showing compliance with the 85%/75% limits. Thus, operators acting in good faith can be excused from some of the requirements if the poor instrument availability can be documented to have been caused by conditions beyond the operator's control.

The requirements for annual certification of monitoring systems and certification in units of the standard are presently more stringent than NSPS requirements. However, EPA Headquarters is in progress of eventually implementing such requirements on a national basis. We prefer that IPP meet the more stringent requirements now as opposed to changing them later.

<u>Comments 1e:</u> The draft PSD permit would apparently limit IPP to 0.5 lb/10^6 Btu of NO_x, regardless of coal type, even though the NSPS for the bituminous coal to be fired is 0.6 lb/10^6 Btu. (Numerous additional statements were made regarding how the proposed IPP coal is classified as bituminous coal and how NSPS limits for the coal should be 0.6 lb/10^6 Btu for NO_x. Also, statements were made regarding the lack of any state-of-the-art advance in NO_x control since the revised NSPS were promulgated.)

<u>Response 1e:</u> See Response 7a.

<u>Comment 2e:</u> There are several adverse operational effects associated with the low NO_x operating modes, including slagging, corrosion (tube wastage), and reduced operating margin. Individual coals may have properties which cause the adverse effects, but often these effects are difficult to predict before actual operations.

Slagging potential increases in a reducing atmosphere due to the lowering of the ash fusion temperature of most coals. Calculation procedures used by boiler manufacturers to determine furnace slagging and fouling potential were utilized for two units referred to in the background document for NSPS and then compared to actual experienced slagging conditions. Also included was the calculation of slagging potential for IPP type coal. The following table shows the results:

Coal Type	Calculated Fouling Potential	Calculated Slagging Potential	Experienced Slagging
Montana Sub-bit. "B" (Colstrip 1 and 2)	Low	Low	Moderate - Severe
Utah Bit. "B" (Huntington Canyon)	Severe	Low	Moderate - Severe
IPP Bit "B"	High	Low	N/A

As these results indicate, the existing methods for calculating slagging potential are inadequate; even for boilers designed to fire the coals which are being burned, the amount of slagging experiences is high. The normal method to control slagging is to increase the excess oxygen, which in turn will raise NO_x emissions. Slagging problems currently exist for boilers designed to meet the 0.7 lb/10^6 Btu NO_x limitation; further problems of this nature can be expected to occur as the limit for bituminous coal is lowered to 0.6 lb/10^6 Btu (new NSPS). To achieve a limitation of 0.5 lb/10^6 Btu with bituminous coal, in the absence of operating data is beyond the present technical limits on the industry.

Response 2e: See Response 7a. The Huntington Canyon unit, designed in the early 70's, was tested to evaluate the performance of tangentially fired units firing western bituminous coal. Results of the testing showed NO_x emissions ranging from 0.44 to 0.58 lb/10^6 Btu with a 30-day average of 0.54. The applicable NO_x emissions limit for this plant is 0.7 lb/10^6 Btu. Information contained in EPA NSPS background document 450/2-78-005a (page 6-2) states that some new burner designs will permit furnaces to be maintained in an oxidizing environment and will thus minimize potential for slagging at low NO_x operation.

This time period is inadequate to evaluate slagging problems.

Comment 3e: Another consideration in evaluating the side effects of low NO_x operation is the potential for increased corrosion or tube wastage.

Response 3e: See Response 7a.

Comment 1f: An evaluation of the air quality impact by the State of Utah which included all particulate emission sources (including low level fugitive emissions which were not included in the air quality analysis conducted by EPA and the IPP contractor) indicated violations of the PSD Class II increments and the National Ambient Air Quality Standards (NAAQS) off IPP property. Additional information needed from IPP would enable better emission estimates to be made which might indicate that PSD and NAAQS standard would not be violated.

Response 1f: Subsequent to this analysis, IPP provided (via contract with Stearns-Roger) revised fugitive emission estimates. These data were reviewed by EPA and compared to PEDCo estimates. EPA selected the most representative emission rates for each fugitive source (EPA memo dated 5/4/80). These revised emission rates were used to recompute each source's contribution, and the final concentration at each receptor on the Utah Valley Model output was scaled by a factor of 0.3572. This modeling effort assumed that the particulate emissions act as a gas. Recognizing the fact that the larger particles will not remain suspended but will settle out over a distance, we made estimates of what portion of the fugitive emissions from the coal storage piles and coal conveying and transfer operations would settle out before reaching the plant boundary. The settled out fraction was deducted from the modeled concentrations and showed that the annual TSP Class II increment would not be violated. The background concentration when added to the calculated increment concentrations showed that NAAQS will not be threatened.

Comment 2f: Other major sources such as Martin Marietta must be included in the modeling to access compliance with PSD increments and NAAQS.

Response 2f: The Valley screening technique was used to determine the interaction of IPP and Martin Marietta (Memo to Martin Marietta File dated April 29, 1980). This modeling effort showed no significant impact, and it is highly probable that the combined annual impact will also be insignificant.

Comment 1q: The Lynndyl area and the surrounding areas are vital to supply the consumers in the State of Utah with products such as fruit, grain, silage, and dairy products. Pollutants from a plant the size of IPP would be very detrimental, if not totally damaging, to the area.

Response 1q: See Responses 1b, 2b, and 1c.

Comment 2q: Acid rain resulting from the burning of coal causes severe damage to crops, streams and lakes hundreds of miles from the emitting source. The existing clean air standard which governs certain pollutants does not really give us protection against acid rain which is formed when sulfur and nitrogen oxide emissions combine with moisture in the atmosphere. It then falls to earth as sulfuric acid and nitric acid in rain, snow, and dust. Records show this problem has greatly increased in New York destroying some 170 lakes. Scientists at the present time are accumulating evidence of mounting damage from acid rain to soil, forests, crops, and buildings.

Response 2q: EPA is concerned about acid rain problems. Additional knowledge and authority are needed before proper emission limits can be established to eliminate the problem. Acid rain problems have been observed downwind of sources burning high sulfur coal with little or no emission controls. EPA has the authority under the PSD regulations to minimize SO_2 and NO_x emissions by requiring best available control technology (BACT) for plants burning low sulfur coal. The BACT requirements in the IPP permit are more stringent than new source performance standards (NSPS). NSPS for SO_2 would require 70 percent control for the IPP plant while BACT requires 90 percent control NSPS for NO_x would allow 0.6 lbs/10^6 Btu while BACT for IPP requires 0.55 lbs/10^6 Btu.

Comment 3q: The site for construction and operation of the 3,000 megawatt IPP plant near Lynndyl was proposed disregarding the fact that it would pollute an area ideally suited for agriculture. The alternative site in Wayne County is not a suitable agricultural area but does have the coal and water needed for the plant without depriving an agricultural area of water necessary to produce crops. All of these plus factors were ignored for the Wayne County site. This site was rejected because pollution would affect the Class I air quality at Capitol Reef National Park for only 12 to 34 days per year.

Response 3g: See Reponse 1b, 2b, and 1c. The Wayne County site indicated problems in complying with the PSD regulations. IPP and the State of Utah decided no significant pollution is anticipated at the Lynndyl site.

Comment 1h: Region VIII personnel referred to the statement in the preamble to the proposed NO_x standards that high-sulfur eastern coal generally causes more severe tube wastage than low-sulfur western coal, 43 Fed. Reg. 42171 (1978). This language, it was suggested, may support the conclusion that sulfur content should determine the NO_x limit and that, therefore, those using low-sulfur western bituminous coals should meet a 0.5 lbs/10^6 Btu limit. We do not believe it would be proper for the Region to reach such a conclusion. A summary of the reasons provided in the Hunton and Williams letter dated April 17, 1980, are as follows:

(1) EPA established the standards on the basis of coal classification (bituminous vs. subbituminous) and not on sulfur content.

(2) The IPP range of coal quality has properties similar to some eastern coals that were considered by EPA in formulating the standards. They did not separate the standards on the basis of sulfur content.

(3) Given the absence of new information supporting lower NO_x limits on low sulfur bituminous coals, Region VIII must define BACT as 0.6 lbs/10^6 Btu for bituminous coals.

(4) Compliance with a NO_x emission limit more stringent than the recently adopted NSPS limits could introduce corrosion, slagging, and other problems.

Response 1h: The references referred to by Region VIII personnel were the preamble to the final NO_x new source performance standards (44 Fed. Reg. 33586 and 33587 on June 11, 1979) and the background information document for proposed NO_x emission standards (EPA-450/2-78-005a dated July 1978). A reading of the two pages in the preamble clearly states the reason why a 0.5 lbs/10^6 Btu emission limit was not established for both bituminous and subbituminous coals. The following statements are extracted from the preamble: "The severity of tube wastage is believed to vary with several factors, but especially with the sulfur content of the coal burned." ". . . the combustion of high-sulfur bituminous coal appears to aggravate tube wastage, particularly if it is burned in a reducing atmosphere." "Thus, some concern still exists over potentially greater tube wastage during low-NO_x operations when high-sulfur coals are burned. Since bituminous coals often have high-sulfur contents, the Administrator has established a special emission limit for bituminous coals to reduce the potential for increased tube wastage during low-NO_x operation." ". . . CE has stated that it would guarantee its new boilers, when equipped with overfire air, to achieve the 0.6 lbs/10^6 Btu heat input limit without tube wastage rates when eastern bituminous coals are burned." "B&W has noted in several recent technical papers that its new low-emission burners allow the furnace to be maintained in an oxidizing atmosphere, thereby reducing the potential for tube wastage when high-sulfur bituminous coals are burned." See Response 7a for additional jusitification of the .55 NO_x limit.

Comment 2h: Some recommended language was suggested to modify condition (5) in the proposed permit. Under the terms of the recommended changes and other conditions in the draft permit, IPP cannot burn a coal which would be incompatible with the air pollution control equipment or the emission rates. IPP must provide the coal quality data as indicted in the draft permit conditions, as well as the coal quality specification range for the air pollution control equipment, as it becomes available.

Response 2h: Condition (5) in the final permit was modified to alleviate IPP's concerns but will insure EPA's approval of the control equipment design prior to on-site construction of major equipment.

Comment 3h: IPP maintains that the CEM requirements as contained in appendix III are more restrictive than CEM requirements in the new source performance standards (NSPS). Section 169 of the Clean Air Act permits EPA to set emission limits more stringent than applicable NSPS when it is justified by significant new information or developments in control technology capabilities. The Administrator's determination as to the amount of monitoring which can reasonable be required of a source is not subject to the exception in section 169. The NSPS rulemaking reflects the amount of monitoring which the Agency may reasonable require.

Response 3h: See Response 6d. Appendix III requirements include monitor availability limitations which are not more restrictive than NSPS because of the provisions under which poor data availability may be excused by the Administrator. EPA believes that appendix III provides clarifications to the NSPS requirements which will serve to guarantee their enforceability.

Comment 4h: At the April 10, 1980, meeting, it was generally agreed that the term "production weighted average" should be stricken wherever it appears in appendix III and replaced with the term "arithmetic average." Also, that the final sentence of 60.46(a)(g) should be stricken.

Response 4h: Condition (4) was modified to eliminate the production weighted averages from appendix III for the IPP permit and the final sentence of 60.46(a)(g) was removed.

Comment 5h: 60.13(a)(4) should be expanded to afford procedures for use in the event of a negative determination by the Administrator.

Response 5h: EPA has incorporated language to accomodate IPP's concerns.

Comment 6h: No reference is made regarding the inclusion of soot blowing during the Reference Method source test of NSPS. It should not be required until the EPA Administrator has developed a position on how it should be handled.

Response 6h: EPA has established a technique for including soot blowing during source testing and it is to be applied during all performance tests.

Comment 7h: A performance test as defined by the NSPS is a 30-day rolling average. Appendix III requires that all performance tests be run at or above 90 percent of maximum production which conflicts with NSPS and makes no sense from a practical standpoint.

Response 7h: Appendix III was modified to correct this problem.

Comment 8h: NSPS allow calculational procedures to be used to determine compliance with emission limits when less than 100 percent of the data which could be collected is available. NSPS permit use of continuous monitor and reference method test data in performing these calculational procedures. Appendix III would provide that reference method tests could be used only to demonstrate emission levels during the actual period of the test (60.8(g)).

Response 8h: The use of reference method tests in the permit is allowed to augment the required CEM data as provided for in NSPS. Use of reference method testing for compliance can only be valid for the periods of testing due to load and control efficiency fluctuations normally expected during such periods.

Comment 9h: The monitor availability requirements in appendix III are not consistent with provisions in NSPS regulations. To the extent that appendix III requirements are inconsistent with NSPS, they should be changed or deleted.

Responsa 9h: CEM averaging requirements are consistent with the 30-day requirements in NSPS primarily because operators acting in good faith can be excused if poor instrument availability can be documented to have been caused by conditions beyond the operator's control. If CEM equipment is designed and operated to attain 55 percent availability monthly, it will achieve much greater availability for longer averaging times (quarterly and annually). See Response 6d.

Comment 10h: EPA's intended use of significant digits in the emission limits by adding a zero as the final digit could be accomplished more clearly by adding the phrase "not to be exceeded" to the specified emission limits.

Response 10h: The addition of a zero to the emission limits is done to indicate that permissible emissions are those below the stated limit. This is consistent with the EPA enforcement policy.

Commentor No.	Commentor	Date
a	James H. Anthony Intermountain Power Project	1-10-80
b	Jane Whalen Southwests Resource Council	1-15-80
c	Lionel E. Weeks, M.D.	1-14-80
d	F. William Brownell Hunton and Williams	4-01-80
e	Lowell L. Smith and David A. Baker KVB for IPP	4-01-80
f	Alvin E. Rickers Utah Division of Environmental Health	4-14-80
g	193 letters from the general public	4-10/4-17-80
h	Henry W. Nickel Hunton and Williams	4-17-80

APPENDIX III

Continuous Emission Monitoring (CEM) Revision to 40 CFR Part 60 Subparts A and Da, and Appendix B for Direct Determination of Compliance Status with PSD Permits Applicable to Fossil Fuel-Fired Steam Generators

60.1 Expand to include:

(a) For purposes of this PSD permit, the existing provisions of 40 CFR Part 60, Subpart Da (FR Vol. 44, No. 113, pps. 33580 - 33624, June 11, 1979) are applicable, as well as all General Provisions under 40 CFR 60, and the provisions of 40 CFR, Part 60, appendix B, as amended, (FR Vol 40 No. 194, pps 46240 - 46271, October 6, 1975). Certain portions of these provisions are modified and applicable to the facility affected by this PSD permit. These modifications include: (1) deletions, (2) replacement, and (3) expansion of portions of the existing provisions of 40 CFR, Part 60, subparts A and Da, and appendix B.

60.7(a)(5) Delete "30" and insert "45".

60.7(c) Add at end, "unless otherwise approved or changed by the Administrator."

60.7(c)(1) Add at end: "The magnitude of all emissions and parameters as required as defined in 40 CFR 60, Subpart Da, shall be reported in a summary form by cause and range of magnitude above the applicable emission limitations of this permit, beginning at midnight, the first day of each calendar quarter, as given in Table II. A more detailed and comprehensive format for report of other information will be made available upon request. Range Z is to be used when systems have negative bias as demonstrated during any performance specification test under 60.13. Violations of any 30-day requirement will be listed for each day when the requirement was not met."

60.7(c) Expand to include:

(c)(5) The weekly average of seven daily zero and calibration drift values for each week of the quarter for each calibration point (zero and upscale) for each monitor required under Subpart Da, as computed according to paragraph 7.2.4, specification 2, of appendix B, part 60.

(c)(6) Date, time and initial calibration values of each required calibration adjustment made on any monitor unit during the quarter, including any time which the monitor was removed or otherwise inoperable for any reason, including reason why.

(c)(7) The date and results summary of each performance or other evaluation of any portion of the monitoring system during the quarter.

(c)(8) The percent (%) of on-line availability time by week for each modular unit (the total equipment necessary to determine the value of a single emission parameter, e.g. NO_x-ppm) under 60.13(e)(4), 60.47 a(f), and 60.49a and as required in the applicable subpart, as well as a description of down time under 60.7(c)(3) and table III.

(c)(9) All conversion values used to derive the 24-hour and/or 30-day emissions or percent reduction for SO_2 and NO_x, which include, but are not limited to: temperature and/or velocity or volumetric flow rate of stack gases, diluent, moisture, ppm, 10^6 Btu per hour (from heat rate curve), and megawatt production.

(c)(10) ~~The production-weighted average daily (24-hour) emissions for SO_2 and NO_x for each boiler operating day of the quarter.~~

(c)(11) The production-weighted average percent reduction (SO_2 only) and emissions of SO_2 and NO_x for the 30 consecutive boiler-operating days prior to each day of the reporting quarter.

(c)(12) Other information as included in the format for the Excess Emission Report (EER), table I of this paragraph, as per instructions of Tab A. Additional format guidance is available upon request.

60.7(d) Expand to include after "inspection." in line 14: "The file shall also include a record of:

(1) The weekly (specify as received or as fired composites) average Btu per pound and average sulfur and ash content of coal expressed as pounds of sulfur (or ash) per million Btu, including assumptions for later pyrite rejection and bottom ash removal. Sampling and analysis shall be done in accordance with acceptable methods prescribed by ASTM.

(2) All conversion values used to derive the 24-hour and 30-day values for SO_2 and NO_x, which include, but are not limited to: temperature and/or velocity or volumetric flow rate of stack gases, diluent, moisture, ppm, 10^6 Btu per hour (from heat rate curve), and megawatt production."

60.7(e) Expand at end to include: "All excess emissions in Magnitude Ranges C (opacity only), D, and E shall be reported to the Administrator within twenty one (21) days according to the procedures of this section. Opacity excesses need not be included unless they had persisted for at least twelve (12) minutes."

60.7 Expand to include:

(f) When the system output in units of the standard is documented to have any negative bias during any series of test(s) done under 60.13, then all values equal to or greater than 80 percent of the applicable emission limitation of this permit shall be reported under 60.7(c)(1). This shall be done with a designation of "Range Z", as on table I. The reviewing agency will then take into account the document bias (negative and positive) of the system, and evaluate compliance accordingly.

(g) Quarterly reports should be submitted on magnetic tape and in a format approved by the Administrator to the maximum extent possible.

60.8(a) Delete entire paragraph and insert: "Within 180 days after achieving the maximum production rate at which the facility will be operated, but not later than 180 days after the first date which the facility supplies electrical power to the grid on a commercial basis, and at such other times as may be required by the Administrator under the Act, the owner or operator of such facility shall complete performance test(s), described in 60.46a, demonstrating compliance of the facility with the applicable emission limitations of this permit. A written report of the results of such performance test(s) shall be furnished to the Administrator within 60 days of the commencement of such test(s)."

60.8(b) Expand at end to include: "Continuous monitoring shall be used for compliance with SO_2 and NO_x emission limits, and may be used for compliance with opacity limits. At least four (4) runs, 2 hours each, shall be conducted for compliance with particulate limitations.

60.8(c) Delete from line 2: "under such" and insert "at or above 90 percent of maximum production, based on megawatt hours, or at other".

60.8(d) Delete "30" and insert "45." Expand at end to include: "For particulate tests, two (2) runs of the four (4) shall include at least one (1) hour of soot blowing of the air preheaters (unless continuous soot blowing is normally employed, and employed during each test. The average emission shall be calculated based on the proper ratio of normal operating time for the soot blowing and non-soot blowing."

60.8 Expand to include:

(e)(5) "For purposes of efficiently and expeditiously facilitating the tests, on-site analysis, results calculation, and preliminary reporting of SO_2 emissions during all certification or performance tests under 60.8(a) and 60.13(c) unless demonstrated 30 days in advance to be an unnecessary hardship. Previous history of procedures does not constitute hardship."

(g) Any reference method, manual-type test conducted under this section shall be used only to demonstrate emission levels during the actual period of the test.

60.11(a) Delete entire paragraph and insert: "(a) Compliance with particulate emission limits shall be performance tests under 60.8. Compliance with all SO_2 and NO_x emission limits shall be the continuous emission monitoring (CEM) system installed and certified under 60.13. Emission limits for opacity shall be continuously evaluated for compliance using CEM data. Compliance with percent reduction requirements for SO_2 may be based on combined data from CEM and fuel monitoring."

60.13(b) After "prior", delete "to conducting performance tests under 60.8.", and insert, "to the day which the facility achieves maximum production rate and the day which the facility operates on a commercial basis."

60.13(c) Delete, "or within 30 days thereafter." Also include in line 9 after "60 days thereof": "after the commencement of such evaluation unless otherwise approved by the Administrator."

(c)(1) Insert after "appendix B": "as revised herein for the purposes of this permit and at the production load as specified under 60.8(c)."

(c)(4) Expand at end to include: "Continuous emission monitoring systems listed within this paragraph shall be re-evaluated at least once during any 12 calendar months in accordance and demonstrate acceptability with the requirements and procedures for determination of zero and calibration drift (2-hour and 24-hour), accuracy error, and calibration error of measurements contained in the applicable performance specification of appendix B, as revised for this permit, or as prescribed by the Administrator. Reporting shall be according to 60.13(c)."

60.13(d) Delete from line 4, "check" and insert "shall determine the quantitative values for both".

(d)(1) Delete "as near the probe as is practical." and insert "at least at the root of the probe, unless otherwise approved by the Administrator."

Delete the entire second sentence beginning on line 6.

Delete the entire fourth and fifth sentences beginning on lines 14 and 20, beginning with "Every six. . ." and "The gases. . ." respectively, and insert in place: "Each span and zero gas cylinder or cell used in any monitoring system shall be initially analyzed not more than six (6) months prior to use in accordance with EPA Protocol Number One for certifying values in compressed gas cylinders. This protocol requires specific traceability to NBS Standard Reference Materials (SRM's) and is available from EPA upon request. The owner or operator shall supply to the Administrator within 21 days of the commencement of use of such cylinder(s) or cell(s), verification and certification using specific EPA protocol. The owner or operator of an affected facility shall provide the Administrator 30 days prior notice of such an analysis of replacement gas supplies to afford the Administrator the opportunity to have an observer present."

60.13(e) Expand at end to include:

(e)(4) Each monitor modular unit (i.e., each of the following system components as a unit: Opacity, SO_2, NO_x, diluent, and data handling units) of a continuous emission monitoring system as required under 60.13 and 60.47a shall attain a minimal annual (the four quarters of a calendar year) on-line availability time of 85 percent and a minimal quarterly availability time of 75 percent for each individual quarter. Should any given yearly or quarterly availability time for any given monitor module unit(s) drop below these respective limits, the owner or operator shall, within 40 days (unless owner can demonstrate that late delivery was beyond his control) of the end of the first unexcused year or quarter in question, cause to be delivered to the facility site operable, factory tested and compatible monitor module(s) (entire component unit) able to replace the monitor module unit(s) which had unacceptable availability times, unless the owner or operator can document and excuse the unacceptable performance to the satisfaction of the Administrator, within thirty (30) calendar days of the end of such year or quarter, as provided for in 60.13(e)(4)(ii).

(e)(4)(i) The data reported under the provisions of 60.49a(c) shall not be counted for purposes of showing compliance with (e)(4) above.

(e)(4)(ii) Documentation of such an excuse shall include at least one (1) of the following and shall be submitted in writing, including all supporting documents:

1. That the reason for the poor specific availability time had not caused another previous occurrence of unacceptable availability within the last two years, and the reason for the particular unavailability in question will be prevented in the future by a more effective maintenance/parts inventory program, or

2. That the entire system is once again fully operable and has been for at least 7 continuous days immediately prior to the report, and parts (as applicable) which had failed are in stock at the facility, or

3. The excused period of unacceptable availability is a period during which the provisions of 60.13(e)(4) were not met primarily because a component or modular unit of the monitoring system had malfunctioned, and this malfunction could not have reasonably been anticipated by the owner or operator to have occurred. An occurrence of a malfunction which could not have reasonably been anticipated to occur is a condition of improper operation of the component or modular unit which (in view of the past experiences of either the vendor or the operator in operating such equipment of the specific type) had not occurred with enough frequency in the past, such that an operator in compliance with the provisions of 60.13(e)(4) of this paragraph could have taken the necessary steps (parts inventory, vendor delivery, and/or trained maintenance personnel, etc.) to be able to resolve such a malfunction condition and provide system availability times as provided for in 60.13(e)(4) above. A condition of improper operation for which the vendor normally, (a) stocks necessary repair parts, etc, (b) itemizes such necessary parts on any suggested parts inventory list for the user, or (c) suggests periodic preventive maintenance checks in order to check for such improper operation, will be a condition which could have been reasonably anticipated by the owner or operator, and therefore, will not be excused.

(e)(4)(iii) Availability time may be recalculated by the Administrator after excluding any unavailability period(s), excused under this section.

(e)(5) Within 30 days after the Administrator notifies the owner or operator (using reports submitted under 60.7) that two non-overlapping periods of unexcused, unacceptable system availability (yearly, quarterly, or combination) have occurred, and the provisions of 60.13(e)(4) have not been met, then the owner or operator shall install, calibrate, operate, maintain, and report emission data using the second compatible module unit(s) then on the facility site, delivered under 60.13(e)(4), unless the condition under 60.13(e)(4)(ii)(2) is documented by the owner or operator within 30 days of the end of the year or quarter to be applicable.

(e)(6) Within 60 days of the date of installation under Section 60.13(e)(5), the owner or operator of the affected facility shall complete a full performance evaluation of the entire

MPT 990 MW
Z 495 MW

continuous monitoring system for that pollutant under 60.13(c) as revised herein, showing acceptability of the system in question according to appendix B as revised for this permit, unless the module unit in question was the data handling unit alone. Within 30 days of the commencement of such evaluations tests, the owner or operator shall furnish to the Administrator a minimum of two copies of a complete written report of such evaluation and test conducted above, demonstrating acceptability of the system according to 60.13 as amended herein. If the performance of any other module unit is affected by the unit in question, then these other unit(s) shall be reevaluated as well.

60.13(h) In the third sentence after ". . . opacity", insert the following "and fuel monitoring".

60.41a At the end, delete the definition of Boiler Operating Day. . . and insert after "period during which", the following: "the facility produced at least 50% of the maximum electrical power which is possible when operating at maximum production for 24 continuous hours."

60.43a(a)(2) Delete "30" and insert "10", and delete "70" and insert "90".

60.43a(a) Expand to include: "(3)65 ng/J(0.150 lb/million Btu) heat input, based on the production-weighted average emissions of any 30 consecutive boiler operating days."

60.43a(g) Insert after "under" in line 3, "60.43a(a)(1) and (a)(2) of".

Insert at end: "Compliance with the emission limitation under 60.43a(a) of this section is determined by calculating the production-weighted average emissions for any averaging period from the individual hourly values, for each hour during which production was maintained.

60.46a(e) Insert after "60.43a", "(a)(1) and (a)(2)", and insert at end: "Compliance with all requirements under 60.43a shall be as provided for under 60.43a(a)(g)".

60.46a(f) Insert after "60.43a", "(a)(1) and (a)(2)".

In the third (last) sentence, delete "first" and insert "last"; also, delete "60" and insert "180"; and delete "initial startup of the facility." and insert: "the first date which the facility supplies electrical power to the electrical grid system on a commercial basis. On each of the 30 successive boiler operating days of the above performance tests, the facility shall demonstrate compliance with the limitations under 60.43a(a)(3)."

60.46a(g) [redacted](1) [redacted] the [redacted], du[redacted]

60.46a Expand to include: "(i): The method of calculating the emission values for the requirements under 60.43a, and 60.44a and other applicable, provisions of this permit shall be the F-factor method, as related to production level (megawatts). The heat rate curve will be verified and may be revised by EPA in reviewing plant production and fuel records during the first 24 months of normal operation according to coal quality and production. Calculations are made using the individual values, properly weighting these values, relative to the production level at the time when the value was recorded."

60.47a(e) After "(b), (c)", insert "(j),".

Expand at end to include: "In addition, the availability requirements under 60.13(e)(4)-(6) will also be met."

60.47a(f) In the first sentence, line 5, delete "will" and insert, "may, for the purposes of meeting the availability requirements under 60.13(e)(4)-(6),". Also expand at end to include: ", or more data as necessary to meet the conditions of this permit."

$18/24 \times 22/30 = 55\%$

Expand at end to include: "If this amount of data (55%) is not collected for each 30 successive boiler-operating days, using either the provisions of this paragraph or other methods acceptable to the Administrator, then the owner or operator shall not be considered in compliance with this section. The provisions of 60.13(e)(4) do not apply to these data requirements under 60.47a(f)."

60.47a(g) Expand at end to include: "The 1-hour averages used to calculate emission rates under 60.43a(a)(3) as specified in 60.46a(g) are expressed in pounds per million Btu heat input, which are then arithmetically averaged for each production hour for a specific day."

60.47a(h) Delete "will" and insert "may".

60.47a(i)(2) Insert after "nitrogen oxides": "or EPA Protocol Number One".

60.47a(i)(4) Delete "(b)" and insert "(i)".

60.47a(i) (5) Delete the remainder of the sentence following: " . . . the outlet of the sulfur dioxide control device is" and insert after: "device is," the following: "250 ppm, or as otherwise specified by the Administrator."

60.47a Expand at end to include:

(j): The owner or operator of an affected facility shall install, calibrate, maintain, and operate continuous monitoring systems, and record the output of the systems, for determining: 1) The total amount of electrical power (MWH) produced each hour of each day; 2) the approximate amount (not necessarily a measurement value) of moisture in the stack, if moisture is added to the system after the economizer; 3) the total volumetric flow rate of gas to the atmosphere. This may be related to the design (or EPA-verified) heat rate curve and the EPA F-factor and tied to the production monitor above, taking into account temperature, pressure, and excess air.

60.48a(a) (4) Delete: "(32°F)" and insert: "(320°F)".

60.49a(c) Insert in the first sentence after "60.47a", the following: "and 60.13(e)", and after " . . . 30 successive boiler operating days", the following: "or if the requirements of 60.13(e)(4)-(6) are not met solely by the CEM system,".

Performance Specification 2 -- SO_2 and NO_x Stack Monitors

3.1 Delete: "concentration", and insert in place: "emission in units of the standard."

3.1.3 Insert after "units," "or emissions in units of the standard."

3.3 Delete: "concentration" from lines 4 and 8, and insert "emission" in both places.

3.9 Insert after "wall" "as determined by Method 6 or 7 testing or as approved by the Administrator."

3.10 Conditioning Period. A minimum period of time, as noted in 60.13(b)(1), prior to the performance tests of 60.8 and 60.13(c) during which the entire continuous monitoring system shall be operated according to paragraph 6.2.1. of this specification."

3.10 Table 2-1 of paragraph 5 is revised to delete accuracy specification number 1 and include:

1.a.	Combined Accuracy Error and Precision Error........	≤ 20 pct (absolute value) the mean emission value of the reference method test data.
1.b.	Precision (confidence interval).............	≤ 10 pct (absolute value) of the mean emission value from reference method test data."
2.	Calibration Error.......	3.5 pct (each 50 and 90 percent of span
4.	Zero Drift (24h)'...	2 pct of span.
5.	Calibration Drift (24h)'....	2 pct of span.

6.1 Delete the last sentence and insert: "This will be satisfactorily accomplished in the field during the operational test period, and prior to the relative accuracy tests under paragraph 6.2."

6.2.2.1 Expand at end to include: "During these tests, the facility shall operate at a minimum of 90 percent maximum load, according to 60.8(c)."

7.2.1 In lines 31-36, delete the sentence: "Accuracy is reported... mean reference method value.", and insert in place: "Accuracy error is reported as the absolute value of the mean of the arithmetic differences in emission values (in units of the standard) expressed as a percentage of the mean reference method value. Precision error is reported as the absolute value of the 95 percent confidence interval of the mean arithmetic differences in emission values (in units of the standard), expressed as a percentage of the mean reference method value."

Figure 2-3, "Accuracy (and precision errors) Determination", is revised herein, according to Figures 2-3(a) and 2-3(b).

7.2.8 Expand at end to include: "The entire continuous monitoring system shall perform and meet all specification of paragraph 5 within the required time limitations of 60.8(a), 60.12(c), and 60.13(e)(6)."

Figure 2-3(a) Accuracy and Precision Error Determination (SO_2)

Test No.[1]	Date and Time	Reference Method Values: Sample [illegible] (ppm)	Average [illegible] (ppm)	lbs. SO_2/10^6 BTU	System[2] Emission Value lbs. SO_2/10^6 BTU	Difference lbs. SO_2/10^6 BTU
1.						
2.						
3.						
4.						
5.						
6.						
7.						
8.						
9.						

Mean Reference Method Value lbs. SO_2/10^6 BTU	
Mean System Value lbs. SO_2/10^6 BTU	
Mean Difference lbs. SO_2/10^6 BTU	

Accuracy Error, % (absolute value) = $\dfrac{\text{Absolute value of the arithmetic differences} \times 100}{\text{Mean reference method value}}$

Precision Error, % (absolute value) = $\dfrac{\text{Absolute value of the 95\% C.I. of the arithmetic differences} \times 100}{\text{Mean reference method value}}$

1. In units of the standard
2. Explain and report method used to determine integrated averages of system values during corresponding 20-minute or 1-2 minute periods, respectively, of SO_2 or NO_x reference method testing.

Rev. 5/80

Figure 2-3(b) Accuracy and Precision Errors Determination (NO_x)

Test No.	Date and Time	Reference Method Values: Samples ppm (dry) 1	2	3	Average ppm (dry)	Average NO_x (dry)	lbs. NO_2 / 10^6 scf	System[2] lbs NO_2/10^6	Difference lbs NO_2 / 10^6 scf
1.									
2.									
3.									
4.									
5.									
6.									
7.									
8.									
9.									

Mean Reference Method Value $\frac{lbs\ NO_2}{10^6\ scf}$	
Mean System Value $\frac{lbs\ NO_2}{10^6\ scf}$	
Mean Difference $\frac{lbs\ NO_2}{10^6\ scf}$	

Accuracy Error, % (absolute value) = $\frac{\text{Absolute value of the arithmetic differences}^1 \times 100}{\text{Mean reference method value}}$

Precision Error, % (absolute value) = $\frac{\text{Absolute value of the 95\% C.I. of the arithmetic differences}^1 \times 100}{\text{Mean reference method value}}$

1. In units of the standard
2. Explain and report method used to determine integrated averages of system values during corresponding 20-minute or 1-5 minute periods, respectively, of SO_2 or NO_x reference method testing.

Rev. 5/80

TABLE I

QUARTERLY EXCESS EMISSIONS REPORT (EER)
For Fossil Fuel-Fired Steam Generators, Subpart D
Format for Sources in Region VIII*
Minimum Requirements Under Section 60.7 (See Tab A)

Part 1. This report includes all the required information under section 60.7 for:

a. Quarterly emission reporting period ending: (circle one)

Mar. 31 June 30 Sept. 30 Dec. 31

b. Reporting year: ____________

c. Reporting date: ____________

d. Person completing report: ____________

e. Station name: ____________

f. Plant location: ____________

g. Person responsible for review and integrity of report:

h. Mailing address for person in 1-g above:

i. Phone number for 1-g, above: ____________

Part 2. Instrument Information: Complete for each instrument:

a. Monitor type (circle one):

Opacity SO_2 NO_x O_2 CO_2

b. Manufacturer: ____________

c. Model no.: ____________

d. Serial no.: ____________

e. Installation date: ____________

Part 3. Excess emissions (by pollutant)

Use Table II: Do not complete for diluent monitors; attach separate narrative per instructions. Use format of Table II for computer-produced reports. Also, include other information as required under 60.7.

Rev. 5/80

Table I (Continued)

Part 4. Conversion factors (as applicable for specific systems)

a. Diluent measured (O_2 or CO_2) ______________

b. F-Factor value used ______________

i. Published or developed ______________

ii. F, Fc, or Fw ______________

c. Basis for gas measurement data (wet or dry)

d. Zero and Cal values used, by instrument:

	Opacity(%)	SO_2(ppm)	NO_x(ppm)	Diluent (% or ppm - circle one)
Zero				
Cal				

Part 5. Continuous Monitoring System operation failures

See Table III: Complete one sheet for each monitor, including diluent: attach separate narrative per instructions.*

Part 6. Certification of report integrity, by person in 1-g, above:

THIS IS TO CERTIFY THAT TO THE BEST OF MY KNOWLEDGE, THE INFORMATION PROVIDED IN THE ABOVE REPORT IS COMPLETE AND ACCURATE.

NAME ______________________

SIGNATURE ______________________

TITLE ______________________

DATE ______________________

*Suggested Format for Subpart D and Da sources in: Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming

TABLE II - Excess Emissions Summary by Week 1 8

OPACITY: Week 6 ______ Day 7 ______ Limit ______

Excess Emission Range Category	Percent of Emission Limit	Number of 6-Minute Periods During Day 2	Reason Codes 3
A	100-125		
B	126-150		
C 5	151-175		
D 5	176-225		
E 5	> 225		

SO_2: Week 6 ______ Limit ______

Excess Emission Range Category	Percent of Emission Limit	Number of 24-Hour Periods During Week 2	Reason Codes 3
Z 4	80-100		
A	101-108		
B	109-120		
C	121-135		
D 5	136-155		
E 5	> 155		

NO_x: Week 6 ______ Limit ______

Excess Emission Range Category	Percent of Emission Limit	Number of 24-Hour Periods During Week 2	Reason Codes 3
Z 5	80-100		
A	101-108		
B	109-120		
C 5	121-135		
D 5	136-155		
E 5	> 155		

1 Format to be used in automatic data-handling systems;

2 As defined in 40 CFR 60, Da.

3 List in descending order the four most frequent codes, by number, followed in parentheses by the number of occurrences of the reason.

4 To be reported by systems with negative bias in accuracy (not counting absolute value), as documented under 60.13; see 60.7.

5 To be reported within twenty-one (21) calendar days under 60.7(e)

6 Begin Sunday morning at midnight; list date of the Sunday starting the week.

7 List the day of the week; e.g., Tuesday.

8 Additional information required under 60.7, 60.13, and 60.49a shall be supplied in a format acceptable to the Administrator.

Rev. 5/80

TABLE III

Continuous Monitoring System Operation Failures

Date	Time* From - To	Instrument	Effect on Instrument Output

* Attach narrative of causes, etc.

Rev. 5/80

TAB A

Instructions for Completing the Quarterly Excess Emissions Report (EER) for Fossil Fuel Fired Steam Generators

1. Complete a separate report for each instrument installed under Part 60, Subpart Da (Table I)

2. Complete Part 1, as shown--be sure to check the reporting period. Indicate address and phone number of person(s) responsible for report validity.

3. Submit information in Part 2, Subparts (a)-(e) for <u>each</u> instrument.

4. Use Table II as a guideline in Part 3 to report all excess emissions as defined in applicable subpart. <u>Report all excess emissions</u>. Sequential numbering of each excess emission is recommended. On a separate sheet of paper, indicate in narrative form for each excess emission (by excess emission number): (1) nature and cause, (2) time and duration, and (3) the action taken to remedy the condition of excess emissions. If no excess emissions occur during the quarter, you must so state. Use Reason Codes if done automatically.

5. Complete Part 4 for each monitor except diluent. State the value and type of F-factor used, e.g., F-9820 dscf/10^6 BTU. State whether you used the published value or developed your own value from ultimate fuel analyses. State the procedure you used for developing this F-factor; you may obtain a guideline for this by contacting John Floyd, EPA, Region VIII, Denver, (303) 837-4261. Indicate the basis for the data--dry or wet (actual stack) conditions--for both the pollutant and diluent monitors. List the values used during the quarter for your zero and calibration point checks on each instrument.

6. Use Table III as a guide in Part 5 to list the times, durations, and effect on data, of all system upsets or malfunctions. Use a separate sheet to explain in a narrative form the detailed nature and extent of problems, repairs, and/or adjustments connected with these system failures, as well as the action taken to return the system to proper operation; include calibration adjustments if made during the quarter. Make additional copies of Table III, as needed.

7. Have the person in charge of the overall system and reporting certify the validity of the report by signing in Part 6.

8. The computer-produced equivalent to Tables II and III will be acceptable. All reports and notifications shall be forwarded as follows: Director, Enforcement Division, USEPA (8E), 1860 Lincoln St., Denver, Colorado 80295 Attn: Roxann Vartzas, Phone, 303-837-2361.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY
RESEARCH TRIANGLE PARK
NORTH CAROLINA 27711

DATE: May 22, 1980

SUBJECT: Clarification of 0.55 lbs/10^6 NO_x Limit for Intermountain Power Project (IPP)

FROM: David G. Lachapelle DGL
Combustion Research Branch (MD-65)

TO: Norm Huey, Chief
Technical Support Section, 8AH-A
Region VIII, Denver, Colorado

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The purpose of this memo is to provide clarification to our memo of 4/21/80 relative to the BACT NO_x emission limit for the Intermountain power project. In that memo we stated that a NO_x emission limit of 0.55 lbs/10^6 Btu is "probably" achievable. That limit was qualified for the following reasons:

- The emission data cited was based solely on tests conducted on Utah Power and Light Company's Huntington Canyon No. 2 unit. This is a tangentially fired boiler built by Combustion Engineering, Inc.

- We have no emission performance data from units built by the other three utility boiler manufacturers (Babcock & Wilcox, Foster Wheeler, and Riley Stoker) burning the same Utah "B" bituminous coal.

- We do not know who will be selected as the boiler manufacturer(s) for the IPP units.

Despite these factors, we feel that a NO_x limit of 0.55 lbs/10^6 Btu on a 30-day rolling average basis can be achieved with state-of-the-art burner and furnace design by any of these utility boiler manufacturers with the coal proposed for IPP. Our Summary statement in the 4/21/80 memo made no attempt to qualify the 0.55 lbs/10^6 Btu limit. Consequently, we have no objection to deleting the word "probably" as it relates to that limit.

cc: Walter C. Barber, OAQPS (MD-10)
John Burchard, IERL (MD-60)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY
RESEARCH TRIANGLE PARK
NORTH CAROLINA 27711

DATE: APR 21 1980

SUBJECT: Technical Assistance on BACT Emission Limit for Intermountain Power Project (IPP)

FROM: John Burchard, Director
Industrial Environmental Research Lab/RTP (MD-60)

Walter C. Barber, Director
Office of Air Quality Planning and Standards (MD-10)

TO: Robert L. Duprey, Director
Air & Hazardous Materials Division, 8AH

The purpose of this memo is to document our response to your technical assistance request dated 4/1/80. Since receipt of that request on 4/4/80, members of our staff have reviewed your transmittal package and evaluated all available data that is relevant to the subject. Further, our staff members have had several telephone discussions with members of your staff during the period 4/7 to 4/10/80.

Our position on the NO_x emission limit for IPP is as follows:

- A NO_x emission limit of 0.6 lbs/10^6 Btu is achievable based on available data and characteristics of the coal proposed for use by IPP. Additionally, the 0.6 standard is consistent with the NSPS promulgated on June 11, 1979 in that the coal proposed for use is classed as bituminous.

- A NO_x emission limit of 0.55 lbs/10^6 Btu is probably achievable based on our experience and field test results at Utah Power and Light Company's Huntington Canyon No. 2 which burned a Utah "B" bituminous coal with chemical/physical characteristics within the range presented for the IPP coal. Additional supporting information is contained in Attachment 1.

- A NO_x emission limit of 0.5 lbs/10^6 Btu (on a continuous basis) cannot be supported based on available data. However, since the IPP units have not as yet been designed, a 0.5 lbs/10^6 Btu limit could be proposed as a goal. This position is based on our understanding that boiler manufacturers can design boilers with more liberal furnace volume, and consequently lower heat release rates. This should reduce furnace slagging potential and permit operation at the 0.5 lbs/10^6 Btu level. Additional supporting information is contained in Attachment 1.

Please keep us advised on the status of this project. If we can be of further assistance, especially after boiler designs are developed, please do not hesitate to contact us.

Attachment

Attachment 1: Experience at Huntington Canyon No. 2, and Its Relevance to IPP

Huntington Canyon No. 2 is a modern tangentially-fired unit built by Combustion Engineering, Inc. It was designed to meet the 1971 NSPS of 0.7 lbs $NO_x/10^6$ Btu. It is equipped with overfire air ports for NO_x control. These ports provide for introduction of up to 20 percent of the total combustion air requirements above the fuel admission nozzles at full unit loading. Additionally, the unit has provisions for fuel/air and overfire air nozzle tilting (± 30 degrees vertically) and separate air compartment flow dampers. Its major design features are:

Generator rating, MW	400
Main steam flow @ MCR (lb/hr)	3,036,000
Reheat steam flow @ MCR (lb/hr)	2,707,000
Superheat outlet temp. (°F)	1,005
Superheat outlet press. (PSIG)	2,645
Reheat outlet temp. (°F)	1,005
Reheat outlet press. (PSIG)	559
Mills (number)	5
Fuel elevations	5

The unit was extensively tested as part of an EPA program (Contract 68-02-1486) to evaluate the performance of tangentially fired units firing western bituminous and subbituminous coals. Testing at Huntington Canyon was performed during the period 4/30/75 to 11/23/75. Results from this study are documented in the final report "Overfire Air Technology for Tangentially Fired Utility Boilers Burning Western U.S. Coal," EPA-600/7-77-117, October 1977.

During the course of this testing, it was found that the degree of NO_x control on this unit firing the Utah "B" bituminous coal was frequently limited by slagging characteristics of the coal. At times, slag deposits became very heavy and running (molten) slag in excess of 4 inches thick were observed. These generally occurred when low NO_x conditions using reduced levels of excess air in the fuel firing zone were attempted. During those periods when clean furnace walls could be maintained, NO_x levels at full load were quite low (about 0.45 lbs/10^6 Btu). However, these were relatively short term tests of about one hour duration.

Following the short term optimized tests, the unit was subjected to a nominal 30-day run under optimized low-NO_x conditions. Unit load followed system demand as scheduled by the dispatcher. Unit load varied from about 200 MW to 425 MW. The average MW loading during the 30-day period was 347 MW. Continuous NO_x monitoring was not performed during this program, but a calculated 30-day average was made based on unit loading and our experience with NO_x levels at various loads and conditions of slagging. On this basis, the NO_x ranged from 0.44 to 0.58 lbs/10^6 Btu, with a 30-day average of 0.54 lbs/10^6 Btu.

There are several important factors that must be appreciated when reviewing this data. First, ash fusion temperature and other coal performance indices and their effect on furnace wall slagging bear very heavily on how a boiler must be operated if load requirements are to be met. Second, the most effective method for controlling slag (in addition to operation of soot blowers) is to increase excess air in the furnace firing zone. This, however, increases NO_x. Third, although low NO_x levels (about 0.45 lbs/10^6 Btu) could be achieved during short-term optimized tests, the real-life situation is somewhat different under routine overfire air operation as evidenced by the 30-day test data. Here, furnace walls at times slagged heavily. When this occurred, the operator would increase excess air to the fuel firing zone to shed slag. This in turn caused NO_x levels to increase. Heavy slag deposits cause furnace heat absorption rates to decrease and furnace temperatures increase with a consequent increase in thermal NO_x. Additionally, it is inadvisable to allow slag deposits to build up too heavily. If this should occur, slag may break off due to its mass and fall into the ash hopper with the risk of an explosion. One need only be present at such an occurrence to become a believer!

Table 1 compares properties of the coal and ash properties for the IPP and Huntington Canyon coals. The analyses lead us to expect that the NO_x emissions levels and slagging potential for the IPP coal should be no different than was experienced with the Huntington Canyon coal. In addition to ultimate coal analysis, ash component analysis and ash fusion temperatures we have included information on other performance indices that are used to estimate a coal's slagging potential. These include the ratios of base/acid, iron/calcium and silica/alumina.

Base/Acid Ratio: This provides a means for understanding ash performance as it occurs under furnace conditions. It is expressed as:

$$\frac{Fe_2O_3 + CaO + MgO + Na_2O + K_2O}{SiO_2 + Al_2O_3 + TiO_2}$$

In general, acidic oxides produce higher melting temperatures and will be lowered somewhat proportionally by the amounts of basic oxides available for reaction. However, these oxides interact chemically at furnace conditions to form complex salts of lower melting temperatures. Generally, ash with a base/acid ratio below 0.25 and greater than 0.80 will exhibit high fusibility temperatures and thus will be less troublesome from the viewpoint of slagging. Ash with base/acid ratios between 0.25 and 0.80 will exhibit lower fusibility temperatures and will be more prone to slag. Both the IPP and Huntington Canyon coals have base/acid ratios that fall within that range. The experience at Huntington Canyon supports this slagging potential.

Iron/Calcium Ratio: Although iron and calcium produce basic reactions, they interact in a complex fashion and produce an eutectic with a lower melting temperature than either alone. This effect is most pronounced when the ratio is in the range of about 0.3 to 3. Typically, ash from Western coals has ratios less than 1.0 and exhibit low fusibility temperatures and thus are more prone to slag. This is again evident for the IPP and Huntington Canyon coals.

Silica/Alumina Ratio: This ratio can give guidance relating to ash fusibility temperature. These oxides are acidic and have high melting temperatures. However, the silica is considered to be more likely to form low melting complexes, e.g., silicates, with basic constituents than is the alumina. With coals having equal, or near equal, base acid ratio, the one having the higher silica/alumina ratio will produce lower fusibility temperatures and be more prone to slag. The ash analysis for IPP suggests this possibility.

Summary

Our analysis of relevant field test data and coal and ash properties leads us to believe that attainment of a NO_x emission limit in the range of 0.55 to 0.60 lbs/10^6 Btu is achievable for IPP. A NO_x emission limit of 0.5 lbs/10^6 Btu is not supported based on available data. Nonetheless, the more stringent limit is not unreasonable as a goal. We feel that attainment of the 0.5 limit on a continuous basis may be limited by slagging characteristics of the coal as experienced on a modern unit. This does not preclude incorporation of other design features, such as enlarged furnace volume, to minimize slagging in a new unit design. Further, experience with low-NO_x burner design for both wall-fired and tangentially fired units should be available in about two years and should provide a defensible basis for more stringent NO_x emission limits.

Table 1. Comparison of Coal and Ash Properties

Ultimate Analysis (Weight percent, as fired)

	IPP coal	Huntington Canyon coal
Carbon	62.35-75.42	66.80
Hydrogen	4.32- 5.30	5.23
Oxygen	9.26-14.93	9.80
Nitrogen	1.02- 1.46	1.28
Sulfur	0.44- 0.78	0.45
Moisture	4.50-10.46	7.99
Ash	4.29- 9.77	8.45
HHV, (Btu/lb)	11,900-13,650	12,113

Ash Analysis (Weight percent)

	IPP coal	Huntington Canyon coal
Fe_2O_3	3.53-10.75	4.7
CaO	4.82-20.65	8.9
MgO	0.96- 4.68	1.1
K_2O	0.22- 1.21	0.6
Na_2O	0.07- 3.88	5.2
SO_3	3.38-14.63	6.6
P_2O_5	0.04- 0.51	-
SiO_2	35.88-65.43	51.5
Al_2O_3	8.34-18.21	17.0
TiO_2	0.26- 1.04	1.0

Ash Fusion Temperature (Oxidizing, °F)

	IPP coal	Huntington Canyon coal
Initial Deformation	2130-2425	2130
Softening (H=W)	2140-2435	2200
Fluid	2170-2455	2450

Other Performance Indices:

	IPP coal*	Huntington Canyon coal
Base/Acid Ratio	0.37	0.30
Iron/Calcium Ratio (Fe_2O_3/CaO)	0.56	0.53
Silica/Alumina Ratio (SiO_2/Al_2O_3)	3.82	3.03

* These are calculated ratios based on ash analysis. Since a range of values was given for the IPP coal, midpoint averages were selected for the calculation. Consequently, these performance indices should be considered only as a guideline.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

DATE May 30, 1980

SUBJECT IPP Fugitive Emissions Annual Impact Analysis

FROM Technical Support Section -- 8AH-A

TO IPP Files

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During the reopened public comment period beginning March 27, 1980, the Utah State Department of Health raised three basic concerns (letter Keller to Rickers, April 3, 1980) about the proposed PSD permit for the IPP Generating Station.

First, insufficient engineering details had been provided by the Company to adequately characterize emission rates from the various fugitive sources.

Subsequently, such details on emission rates were provided by Stearns-Roger, engineering consultant to the Company (letter, Packnett to Huey, April 24, 1980). These data were reviewed by EPA and compared to PEDCo emission estimates (report, October 25, 1979) whereupon EPA selected the most representative emission rates for each fugitive source (memo, Dale to the File, May 21, 1980).

Stack emissions did not show this.

Second, modeling of the fugitive and tall stack emissions by the State showed exceedences of the annual Class II increments for particulates and of the secondary NAAQS for particulates off of but near Company property.

Per the preferred emission rates selected by EPA as mentioned above, each source contribution was recomputed and the final concentration at each receptor on the Utah Valley model output was scaled by a factor of 0.3572. Table 1 shows the emission and source contribution data. The scaling factor was obtained by dividing column 6 (EPA source contributions) by column 5 (Utah model source contributions) on table 1. The resulting scaled ground level concentrations are shown in figure 1. On that figure, isopleth outlines the area in which the annual Class II particulate increment is exceeded. This isopleth extends off plant property (solid line redrawn from engineering diagrams) by a distance of no greater than about 400 m. Adding the routinely expected background concentration for this area, 24 ugm/m^3, to the highest scaled interpolated concentration off plant property, also about 24 ugm/m^3, yields a total concentration off plant property of near 48 ugm/m^3. Thus, the annual secondary NAAQS for particulates of 60 ugm/M$_3$ is not threatened.

The Valley Model makes the assumption that all particulate emissions behave as a gas, that is none of the particles are assumed to be influenced by gravity. Therefore, EPA undertook an investigation of particle size frequency distribution of coal dust to determine if any of the IPP particulate emissions might be deposited before leaving plant property.

CFPO

DIST	CC	AT
IPP BRD		
IPA BRD		
JHA		
R[illegible]		
[illegible]		
ATD		
JCF		
CDH		
HLH		
WMH		
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FK		
HML		
JLW		
THM		
RN		
VLP		
GRS		
RDS		
BMT		
[illegible]		
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FILE		
PER JHA		

EPA Form 1320-6 (Rev. 3-76)

A 1978 PEDCo publication, "The Survey of Fugitive Dust from Coal Mines," provides a composite size distribution of particles from coal storage areas. From that publication a size distribution was obtained for the dust emitted from the storage areas and the coal conveying and transferring operations. (See table 2.)

The mass mean diameter was calculated for each category using the equation:

$$\bar{d} = \left(\frac{d_2^3 + d_2^2\, d_1 + d_2\, d_1^2 + d_1^3}{4} \right)^{1/3}$$

Each particle was assumed to settle according to Stokes Law given as

$$V_g = \frac{2r^2\, g\rho}{9\mu}$$

The distances to where all the particles in a size category reach the ground is listed in table 2. The maximum concentration predicted by the Valley model at the plant property boundary on the north is interpolated to be 21.1 μgm/m^3 and on the south to be 24.0 μgm/m^3.

The coal piles are between 850 and 1,160 meters from the north boundary and 1,980 meters from the south boundary. The conveying and transfer operations are about 1,190 meters from the north boundary and between 1,490 and 1,740 meters from the south boundary. From table 2, 19 percent of the coal pile emissions will fall out prior to reaching the north boundary and 47 percent prior to reaching the south boundary. Twenty-five percent of the coal conveying and transfer emissions will fall out prior to reaching the north boundary or south boundary. The maximum concentrations, taking into account deposition of the larger coal particles, was determined to be 18.6 μgm/m^3 at the north property line and 18.0 at the south property line (see table 3).

The allowable Class II increment is 19 μgm/m^3.

Richard W. Fisher
Meteorologist

Table 1 - Emissions and Source Contributions for the IPP Generating Station [illegible] by Utah Department of Health and EPA, Region VIII

Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
Source	Utah Modeled Emission Rate tons/yr	Revised EPA Emission Rate tons/yr	Ratio (Col. 3/Col. 2)	Source Contributions Utah Model (ugm/m^3)	Source Contributions EPA Model (Col. 4 x Col. 5)
Stack 1 and 2	2,137.0	2,137.0	1.00	.002971	0
Coal unloading and crushing	30.9	3.0 1.5 4.5	0.15	7.90	1.15
Coal conveying and transfer	8.0	25.0 5.9 30.9	3.86	0.69	2.67
Coal storage	195.0	120.8	0.62	17.84	11.05
Ash silo vents	568.0	- 0 -	- 0 -	30.27	- 0 -
Ash silo unloading	94.0	94.0	1.00	8.39	8.39
Total	3,032.9	2,387.2	---	65.10	23.26

Table 2 - Deposition Calculations

Particle Size Categories (μm)	Category Frequencies %	Mass Mean Diameter d(μm)	Radius r(μm)	Settling Velocity (Stokes Law) V_g(m/s)	Distance Downwind to Settling X(m)
.1 - 10	13%	6.3	3.15	0.2	27,300
11 - 20	40%	15.9	7.95	1.1	4,963
21 - 30	22%	25.8	12.90	3.0	1,820
31 - 35	6%	33.0	16.50	4.9	1,114
36 - 40	12%	38.0	19.00	6.4	853
41 - 50	7%	45.6	22.80	9.3	587

Table 3 - Interpolated Maximum Concentrations at Plant Boundary

	Source Contributions		Source Contributions Including Deposition	
	at North Boundary	at South Boundary	at North Boundary	at South Boundary
Stack 1 & 2	0	0		
Coal unload & crush	1.04	1.19	1.04	1.19
Coal conveying & transfer	2.42	2.76	1.82	2.07
Coal storage	10.02	11.40	8.12	6.04
Ash silo vents	0	0	0	0
Ash silo unloading	7.61	8.66	7.61	8.66
Total	21.1	24.0	18.6	18.0

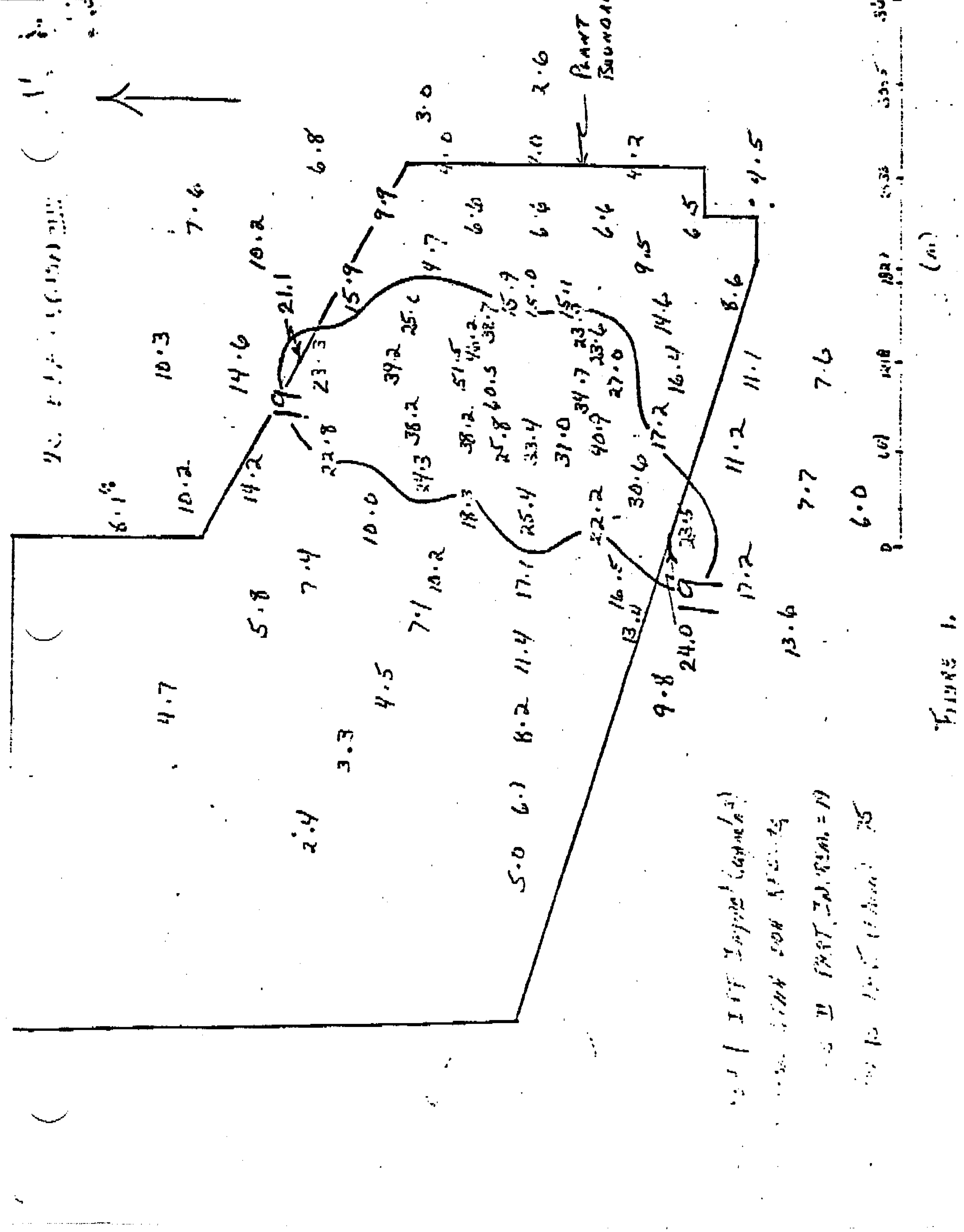

FIGURE 1.